POROSITY DETERMINATION
CTV III

Model Porosity

Static Modeling Porosity

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5 µsec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from XRD or FTIR. Core data from two wells with 13 data points was used to develop a permeability transform (**Figure 3**). An example of the transform from core data is illustrated in **Figure 1**.

Figure 2 shows porosity and permeability histograms [redacted]. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. **Figure 4** shows the distribution of permeability and porosity using Sequential Gaussian simulation (kriging) within the static model.

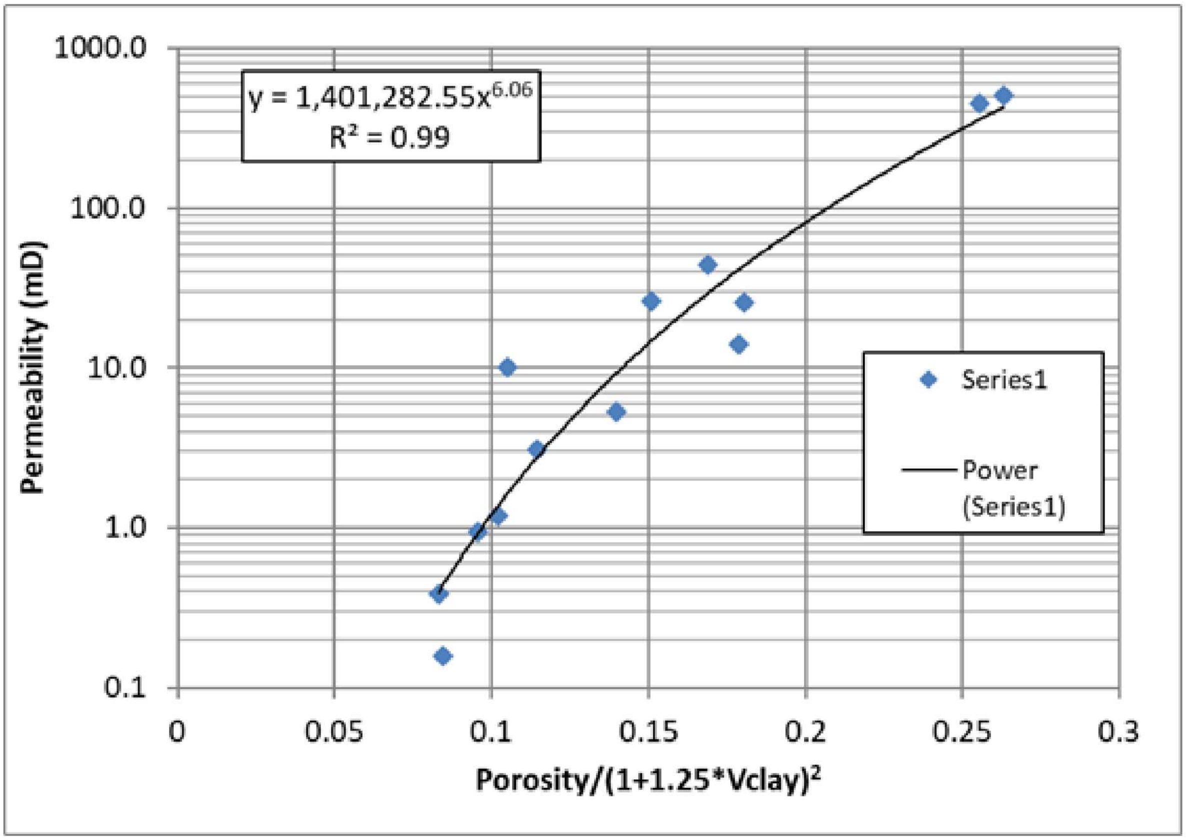

Figure 1: Permeability transform for Sacramento Basin zones

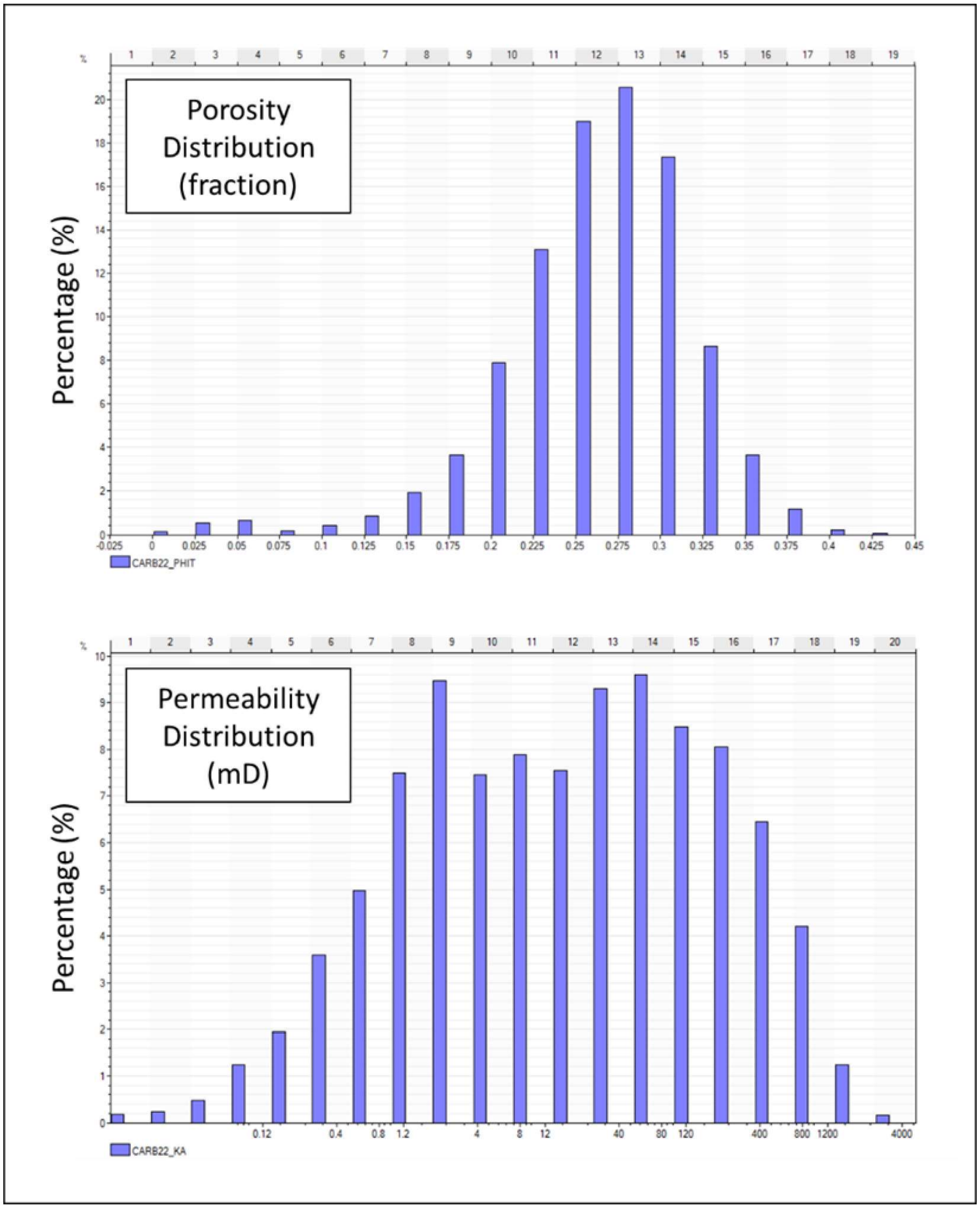

Figure 2: [redacted] porosity and permeability distribution in the static model.

[redacted]

Figure 3: Location of wells with core data used for permeability transform.

[redacted]

Figure 4: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.